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Geological Survey

Proposed Order Governing Oil and Gas Operations on the Outer Continental Shelf of the Arctic Ocean

DEPARTMENT OF THE INTERIOR

Geological Survey

Proposed Orders Governing Oil and Gas Operations on the Outer Continental Shelf of the Arctic Ocean

Notice is hereby given that, pursuant to Title 30 CFR 250.11, the Chief, Conservation Division, U.S. Geological Survey, has proposed Orders Nos. 1, 2, 3, 4, 5, 7 and 12 governing oil and gas lease operations on the Outer Continental Shelf (OCS) of the Arctic Ocean. These Orders will be applicable to OCS lands in the Beaufort Sea, the Chukchi Sea, and the Hope Basin.

These proposed Orders were developed from the revised Area OCS Orders which were published in final form in the **Federal Register** on May 18, 1979, Vol. 44, No. 98.

These proposed Orders do not reflect the revision of the existing regulations which are required by the enactment of the OCS Lands Act Amendments of 1978. It is recognized that some of these requirements will be reorganized and restructured when the existing regulations are revised to reflect the enactment of the OCS Lands Act Amendments of 1978.

The portions of the Orders which have been revised to reflect requirements for Arctic conditions are indicated in italics. Comments are solicited on these italicized portions and any other portions of the Orders which should be revised to include additional requirements pertaining to environmental, geological, or geophysical conditions which may be encountered in the Arctic Area.

A proposed Arctic Area OCS Order No. 8, containing requirements pertaining to the verification of the structural integrity of platforms and other structures including gravel and/or ice islands, is now being developed and will be published at a later date, with a solicitation for comments.

Copies of the U.S. Geological Survey standards which are referenced in OCS Order No. 2 are available from: Chief, Conservation Division, U.S. Geological Survey, Mail Stop 620, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092.

Interested parties may submit written comments and suggestions on the proposed Arctic Area OCS Orders to the Chief, Conservation Division, at the address above, on or before July 30, 1979.

For further information, contact Mr. Richard B. Krahl, Chief of the Branch of Marine Oil and Gas Operations, Conservation Division, U.S. Geological Survey, Mail Stop 620, Reston, Virginia 22092 (703–860–7531). The primary author of this document is Mr. Rodney Smith, Area Oil and Gas Supervisor, Alaska Area, 800 "A" Street, Suite 109, Anchorage, Alaska 99501 (907–271–4303).

Dated: June 8, 1979.

J. R. Balsley,

Acting Director.

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DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division, Western Region

ALASKA AREA—ARCTIC

OCS Order No. 1, Effective

Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37.

1. *Identification of Fixed Platforms or Structures.* Platforms and structures shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimeters (12 inches) in height with the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the platform or structure is located.

d. The platform or structure designation.

The information shall be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area. The identifying sign on the platform would indicate: BOC-SAL-999-C.

2. *Identification of Mobile Drilling Units.* Floating semisubmersible platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimeters (12 inches) in height affixed to the derrick so as to be visible to approaching traffic and containing the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the drilling unit is located.

d. The OCS lease number.

e. The well number.

3. *Identification of Wells.* The OCS lease and well numbers shall be painted on, or a sign affixed to, the wellhead of each singly completed well. In multiple completed wells, each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* All subsea objects resulting from lease operations which are determined by the U.S. Coast Guard District Commander to be hazards to navigation or to the deployment of commercial fishing devices shall be identified by suitable aid-to-navigation devices as directed by the District Commander. Prior to the establishment of a subsea object or in the event of the accidental submergence of an object, the owner shall inform the District Commander of the object's description, location, and unobstructed depth of water above the object's highest point. Based on this information, the District Commander will determine what marking and permits, if any, will be required (14 U.S.C. 83, 85; 43 U.S.C. 1333; 33 CFR Part 67). The owner shall maintain these navigational markings onsite and properly functioning at all times while the obstruction remains.

5. *Departures.* All departures from the requirements specified in this Order shall be

subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,

Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,

Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division,

Western Region

ALASKA AREA—ARCTIC

OCS Order No. 2, Effective

Drilling Operations

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.34, 250,41, 250.91, and the provisions of this Order except for those provisions superseded by the issuance of field drilling rules.

1. *Plans and Applications*

1.1 *Exploration Plan and Development and Production Plan.* In accordance with 30 CFR 250.34, the lessee shall submit Exploration Plans and Development and Production Plans to the Supervisor for approval. All wells drilled under the provisions of this Order shall be included in the appropriate plan. *In addition, the Exploration Plans and Development and Production Plans shall include provisions to deal with emergency situations involving:*

a. A means of drilling a relief well should a blowout occur.

b. Loss or disablement of a drilling unit or a drilling rig.

c. Loss of or damage to support craft.

1.2 *Application for Permit to Drill.* Prior to commencing drilling under an approved Exploration Plan or a Development and Production Plan, the lessee shall file, in triplicate, an Application for Permit to Drill (Form 9–331 C) with the District Supervisor for approval. Additionally, the Supervisor will prescribe the number of public information copies to be submitted. If drilling activity does not commence within 6 months after the approval date, the Permit to Drill will expire.

2. *Drilling from Fixed Platforms and Mobile Drilling Units.*

2.1 *General Requirements.*

2.1.1 *Fitness of Drilling Unit.* All fixed and mobile drilling units shall be capable of withstanding the oceanographic and meteorological conditions for the proposed area of operations. The lessee shall submit evidence to the District Supervisor of the fitness of the drilling unit to perform the planned drilling operation. This evidence shall include drawings and specifications of the following:

a. The rated capacity of all major drilling equipment.

b. Drilling safety systems.

c. Firefighting equipment.

d. Pollution-prevention equipment associated with the drilling operation.

e. A schematic diagram of the drilling unit.

2.1.2 *Pre-Drilling Inspection.* Prior to commencing operations in an OCS Area, all fixed drilling platforms and mobile drilling units shall be made available for a complete inspection by the District Supervisor.

2.1.3 *Well-Site Surveys.* Lessees shall conduct a shallow geologic hazards survey, and other surveys as required by the Supervisor. In Areas where shallow hazards or hydrocarbons are unknown, shallow high-resolution geophysical data shall be obtained. The results of these surveys and an analysis of the geological hazards shall be furnished to the District Supervisor. All data obtained from the surveys and all geophysical data relating to shallow hazards shall be furnished upon request to the District Supervisor.

2.1.4 *Oceanographic, Meteorological, Performance Data.* Operators shall collect and report oceanographic, meteorological, and performance data during the period of operations. The type of information collected, method of collection, and report requirements will be as specified by the Supervisor.

2.1.5 *Subfreezing Operations.* Operators shall furnish evidence that the drilling equipment, drilling safety systems, and other associated equipment and materials are suitable for operations in those Areas which are subject to subfreezing conditions.

2.2 *Mobile Drilling Units.* Applications for drilling from mobile drilling units shall include the following:

a. Maximum environmental design criteria, operational criteria, and a critical operations plan as described in paragraph 9 of this Order.

b. Environmental data, statistical data and calculations which indicate the maximum-anticipated wave, wind, current values, and forces due to ice, icing, storm surges, and seismic motion to be encountered at the drill site during the period of drilling operations.

c. Current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, or other appropriate classifications, with operational limitations.

Unless required by the Supervisor, after a mobile drilling unit has been approved for use in an area, the information detailed in subparagraph 2.1.1 need not be resubmitted unless there are changes in equipment which affect the rated capability of the unit.

2.3 *Fixed Drilling Platforms.* Applications for installations of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with OCS Order No. 8.

3. *Well Casing and Cementing.*

3.1 *General Requirements.* All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. *In addition, the Application for Permit to Drill must include a proposal to fill all annuli within permafrost zones with cement or a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback. The cement used to cement through permafrost zones must be designed to set before freezing and to have a low heat of dydration to prevent excessive thawing of the permafrost zones.* Wells drilled in areas which are underlain by freshwater aquifers shall have casing programs which are designed to protect the freshwater zones. In cases where cement has filled the annular space back to the ocean floor, upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding 12 meters (39 feet) below the ocean floor to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing. If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment in the surface-, intermediate-, and production-casing strings), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall recement or take other actions in accordance with the instructions of the District Supervisor. The lessee shall verify the adequacy of the remedial cementing operations as required by the District Supervisor.

The design criteria for all wells shall consider all pertinent factors for well control, such as:

a. Formation fracture gradients.

b. Formation pressure.

c. Maximum-anticipated surface pressure.

d. Casing setting depths.

e. Permafrost zones. The lessee shall utilize appropriate drilling technology and state-of-the-art methods, such as drilling-rate evaluation, shale-density analysis, or other appropriate methods in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick.

All casing, except drive pipe or structural casing, shall be new pipe which meets or exceeds American Petroleum Institute (API) standards, or reconditioned used pipe that has been tested to assure that it will meet or exceed API standards for new pipe. If casing which is not fabricated to API standards is used, the manufacturer's specifications shall be included on the Application for Permit to Drill (Form 9–331 C).

In permafrost zones, the surface casing shall have minimum axial post-yield strain properties of 0.9 percent in tension and 1.25 percent in compression. Other means for maintaining the integrity of the well from the effects of permafrost thaw may be approved by the Supervisor upon application.

3.2 *Drive or Structural Casing.* This casing shall be set by drilling, driving, or jetting to a minimum depth of 30 meters (98 feet) below the ocean floor or to other depths, as may be required or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement

sufficient to fill the annular space *of the drilled hole* shall be used.

3.3 *Conductor and Surface Casing Setting and Cementing Requirements.*

3.3.1 *Conductor and Surface Casing Setting Depths.* Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the exact setting depths for those wells which may encounter abnormal pressure conditions.

In permafrost-free areas, conductor casing setting depths shall be between 91 meters (298 feet) and 305 meters (1,000 feet) TVD below the ocean floor, and surface casing setting depths shall be between 305 meters (1,000 feet) and 1,400 meters (4,593 feet) TVD below the ocean floor.

In areas containing permafrost, the conductor or surface casing shall be set and cemented after drilling a maximum of 150 meters (492 feet) below the base of the permafrost. Where conditions warrant, the District Supervisor may approve a program where surface casing may be set at a greater depth below the base of permafrost, but not to exceed 1,400 meters (4,593 feet) below the ocean floor.

Engineering, geophysical, and geologic data used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

3.3.2 *Conductor Casing Cementing Requirements.* Conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space *up to the top of the casing.* Cement fill to the ocean floor shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible or possible, *the method of verifying the cement fill shall be approved by the district Supervisor.*

3.3.3 *Surface Casing Cementing Requirements.* Surface casing shall be cemented with a quantity of cement sufficient to protect all freshwater zones, to provide well control until the next string of casing is set, with sufficient cement to fill the annular space to *the top of the permafrost zone, and with the cement fill* at least 60 meters (197 feet) inside the conductor casing, *or as approved by the District Supervisor. Any portion of the annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback.* After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth and maximum mud weight to be used in the intermediate hole.

3.4 *Intermediate Casing Setting and Cementing Requirements.* One or more strings of intermediate casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The setting depth for intermediate casing shall be based on the pressure tests of the exposed formation below the surface casing shoe or on subsequent pressure tests. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth and maximum mud weight to be used in the hole below the intermediate-casing string.

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 150 meters (492 feet) above the zones to be isolated or 150 meters (492 feet) above the casing shoe in cases where zonal coverage in not required. *Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback.*

If a liner is used as an intermediate string, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for intermediate casing. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger string has been achieved. The test shall be recorded on the driller's log. If the test indicates an improper seal, the top of the liner shall be squeeze cemented. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

3.5 *Production Casing.* Production casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a calculated volume sufficient to fill the annular space at least 150 meters (492 feet) above the uppermost hydrocarbon zone must be used. Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the permafrost temperature to prevent internal freezeback.

When a liner is used as production casing below intermediate casing, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for the production casing. Testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners and recorded on the driller's log. If the test indicates an improper seal, the top of the liner shall be squeeze cemented.

3.6 *Pressure-Testing of Casing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed 70 percent of the internal yield pressure of the casing. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained.

Casing:	*Minimum surface pressure*
Conductor	1,400 kilopascals (kPa)(203 psi).
Surface	* 16,900 kPa (1,000 psi).
Intermediate, liner, and Production.	* 110,400 kPa (1,508 psi) or 5 kPa/m (0.22 psi/ft) whichever is greater.

* Must not exceed 70 percent of the minimum internal yield pressure.

In the event of unscheduled drill pipe operations such as an unscheduled side-tracking operation or a fishing operation, the surface pipe shall be pressure tested, calipered, or otherwise evaluated, as approved by the District Supervisor.

After cementing any of the above strings, drilling shall not be resumed until a time lapse of 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's log.

In addition to the time lapse stated above, sufficient time must elapse to allow the bottom 153 meters (502 feet) of annular cement fill, or total length of annular cement fill, if less, to attain a compressive strength of at least 3,448 kPa (500 psi) or as approved by the District Supervisor before drilling resumes.

The typical performance data for the particular cement mix used in the well shall be used to determine the time lapse required.

4. *Directional Surveys.* Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical or the maximum individual inclination survey does not exceed 6 degrees. Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of 3 degrees

from the vertical or the maximum individual inclination survey exceeds 6 degrees. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling and at intervals not exceeding 30 meters (98 feet) in all planned angle-change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 150 meters (492 feet) prior to, or upon, setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the bottom of conductor casing or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Universal Transverse Mercator Grid north or Lambert Grid north shall be made after making the magnetic-to-true-north correction.

5. *Blowout-Preventer (BOP) Equipment Requirements*

5.1 *General Requirements.* Blowout preventers and related well-control equipment shall be installed, used, maintained, and tested in a manner necessary to assure well control.

5.1.1 *BOP Equipment.* Blowout-preventer equipment shall consist of an annular preventer and the specified number of ram-type preventers. The pipe rams shall be of proper size to fit the drill pipe in use. The working pressure of any blowout preventer shall exceed the maximum-anticipated surface pressure to which it may be subjected, except that the working pressure of the annular preventer need not exceed 34,475 kPa (5,000 psi).

Information submitted with the Application for Permit to Drill shall include the maximum-anticipated surface pressure and the criteria used to determine this pressure. All blowout-preventer systems shall be equipped with:

a. A hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 1,400 kPa (203 psi) above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers. The method of BOP actuation control such as hydraulic, acoustic, or other methods, shall be described and included in the Application for Permit to Drill.

b. At least one operable remote blowout-preventer-control station, in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

c. A drilling spool with side outlets, if side outlets are not provided in the BOP body, to provide for separate kill and choke lines.

d. A kill line equipped with 2 kill-line valves is required. The master valve shall be located adjacent to the BOP. This valve shall not normally be used for opening or closing on flowing fluid. The second valve shall be located adjacent to the master valve. This valve shall be used as the control valve.

e. A fill-up line above the uppermost preventer.

f. A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53, First Edition, February 1976, reissued February 1978, Sections 3A and 3B, or subsequent revisions which the Chief, Conservation Division, has approved for use.

g. Valves, pipes, and fittings upstream of, and including, the choke manifold shall have a pressure rating at least equal to the maximum-anticipated surface pressure.

h. A wellhead assembly with a working pressure at least equal to the maximum-anticipated surface pressure.

5.1.2 *Auxiliary Equipment.* The following auxiliary equipment shall be provided and maintained in operable condition at all times:

a. A kelly cock shall be installed below the swivel and an essentially full-opening valve of such design that it can be run through blowout preventers shall be installed at the bottom of the kelly. A wrench to fit each valve shall be stored in a conspicuous location readily accessible to the drilling crew.

b. An inside blowout preventer and an essentially full-opening drill string safety valve in the open position shall be maintained on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string.

c. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole at the time.

5.1.3 *Subfreezing Operations.* The blowout preventers and related control equipment shall be suitable for operations in those Areas which are subject to subfreezing conditions.

5.2 *Subsea BOP Requirements.* The minimum requirements for drilling below the casing strings for subsea blowout-preventer stacks are tabulated below:

Drive or Structural	None required [1, 2]
Conductor	1—Annular
	1—Diverter System [2, 3]
Surface	1—Annular
	2—Pipe Rams
	1—Blind Shear Ram
Intermediate	1—Annular
	2—Pipe Rams [5]
	1—Blind Shear Ram

[1] When drilling fluids are circulated to the drilling vessel, a diverter system as described in subparagraph 5.4.1 shall be installed on top of the marine riser.

[2] If returns to the surface cannot be established, refer to subparagraph 5.4.2.

[3] The choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, can be used for diversion, if approved by the Supervisor, or an annular preventer or pressure-rotating, packoff-type head, equipped with suitable diversion lines, shall be installed on top of the marine riser.

[4] To be installed on top of the marine riser. The diverter system shall provide, as a minimum two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

[5] When a tapered drill string is in use, the BOP stack shall be equipped with pipe rams to fit both sizes of drill pipe.

Subsea blowout-preventer stacks shall be equipped with blind shear rams. A subsea accumulator or a suitable alternate approved by the District Supervisor is required to provide fast closure of the preventers and to operate all critical functions in case of loss of power fluid connection to the surface. The blowout-preventer system shall include dual pod control systems in accordance with API RP 53, First Edition, February 1976, reissued February 1978, Subsection 5.B.13, or subsequent revisions which the Chief, Conservation Division, has approved for use. Prior to the removal of the marine riser for installing casing, the riser shall be displaced with seawater. Sufficient hydrostatic head shall be maintained within the well bore to compensate for the reduction in head and to maintain a safe well condition. If repair or replacement of the blowout-preventer stack is necessary after installation, this work shall be accomplished after casing has been cemented prior to drilling out the casing shoe or by setting a cement or bridge plug to assure safe well conditions.

5.3 *Surface BOP Requirements.* The minimum requirements for drilling below the casing strings for conventional surface blowout-preventer stacks are tabulated below:

Drive or Structural	1—Diverter System [1]
Conductor	1—Annular
	1—Diverter System [1]
Surface	1—Annular
	2—Pipe Rams
	1—Blind Ram
Intermediate	1—Annular
	2—Pipe Rams [2]
	1—Blind Ram

[1] The diverter system shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

[2] When a tapered drill string is in use, the BOP stack shall be equipped with pipe rams to fit both sizes of drill pipe.

5.4 *Drive Pipe or Structural Casing BOP Requirements.*

5.4.1. *Drilling Operations from Bottom-Supported Rigs.* Before drilling below this string with a bottom setting rig, a diverter system and related equipment shall be installed for circulating the drilling fluid to the drilling structure. The diverter system shall be equipped with remote control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well. The diverter lines shall vent in different directions to permit downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9-331 C) to the District Supervisor for approval.

5.4.2 *Floating Drilling Operations.* In drilling operations where a floating or semi-submersible type of drilling vessel is used and formation competency at structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor hole, a program which provides for safety in these operations shall be described and submitted to the District Supervisor for approval. This program shall include all known pertinent information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor-casing seat, and a contingency plan for moving off location.

5.5 *Conductor Casing.* Before drilling below this string, at least one remote-controlled, annular-type blowout preventer shall be installed. A diverter system and other equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed as described in subparagraph 5.4.1.

5.6 *Surface and Intermediate Casing.* Before drilling below these strings, the blowout-preventer system shall consist of at least four remote-controlled, hydraulically operated blowout preventers including at least two equipped with pipe rams, one with blind rams, and one annular type. Subsea blowout-preventer stacks used with floating drilling vessels shall include one set of blind shear rams.

5.7 *Testing of BOP Systems.* Prior to conducting high-pressure tests, all BOPs shall be tested to a low pressure of 1,400 to 2,000 kPa (203 to 290 psi).

5.7.1 *BOP Testing Frequency.* Surface and subsea BOP stacks shall be tested as follows:

a. When installed.

b. Before drilling out after each string of casing has been set.

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. A period of more than 7 days between tests may be allowed where drilling problems prevent testing and remedial efforts are being made, provided BOP tests will be conducted as soon as possible. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

d. Following repairs that require disconnecting a pressure seal in the assembly.

5.7.2 *Pressure Testing Surface BOP Systems.* Ram-type BOPs and related control equipment shall be tested at the maximum-anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever if the lesser. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. Before drilling out of each casing or liner shoe, the blind rams shall be tested as required for pipe rams. When a tapered drill string is in use, the smaller pipe rams shall be tested when the smaller pipe is within the stack during a trip.

5.7.3 *Pressure Testing Subsea BOP Systems.* Subsea BOPs and all related well-control equipment shall be stump tested at the surface with water to the maximum-anticipated surface pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the sea floor, the control equipment and pipe rams, conforming to the drill string within the stack, shall be tested as required under subparagraph 5.7.2. Before drilling out of each casing or liner shoe, the blind shear rams shall be tested as required for blind rams under subparagraph 5.7.2.

5.7.4 *Actuation of Surface BOP Systems.* The following minimum-actuation frequencies are required:

a. Pipe Rams—Daily. In order to prevent damage to the rams, complete closure of the rams on drill pipe is not required, provided proper operation is indicated.

b. Blind Rams—Once each trip while the drill pipe is out of the hole. If multiple trips are made, only one action per day is required.

c. Annular-Type Preventer—Once each week in conjunction with the pressure test.

d. Control Sfations—Once each trip while the drill pipe is out of the hole; however, not more than once each day, if multiple trips are made.

e. Choke manifold valves, kelly cocks, drill pipe safety valves—Weekly.

5.7.5 *Actuation of Subsea BOP Systems.* The actuation frequency requirements for subsea BOP systems shall be the same as those listed in subparagraph 5.7.4 for surface BOP systems, except item "b" pertaining to blind rams.

The blind shear rams shall be actuated once each trip from alternate control stations and control systems; however, not more than once each day, if multiple trips are made. During the weekly pressure tests, all hydraulic systems except those actuating the blind shear rams shall be actuated from each control station and control system.

5.8 *Inspection and Maintenance.* All BOP systems, marine risers, and associated equipment shall be inspected and maintained in accordance with the manufacturer's recommended procedures. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of subsea installations may be accomplished by the use of television equipment.

5.9 *Blowout-Preventer Drills.* All drilling personnel shall be indoctrinated in blowout-preventer drills and be familiar with the blowout-preventer equipment before starting work on the well. A blowout-preventer drill shall be conducted for each drilling crew in accordance with the well-control drill requirements of the U.S. Geological Survey (USGS) Outer Continental Shelf Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS-OCS-T 1), First Edition, December 1977, and subsequent revisions thereto. A BOP drill may be required by a USGS designated representative at any time during the drilling operation.

6. *Mud Program.* The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained readily accesible for use at all times to assure well control.

Mud temperatures shall be controlled to minimize heat loss to and thawing of the permafrost which can result in serious well problems. To insure maximum safety, hydrate zones shall be anticipated and diagnosed quickly, and drilled at controlled rates with mud cooled to the hydrate equilibrium temperature. To prevent problems after hydrate zones are penetrated, cooled muds shall continue to be used, and where possible, hydrate zones should be cased off with high-collapse-strength casing.

6.1 *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's log prior to pulling the drill pipe as follows:

a. There was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

b. The weight of the returning mud is not less than the weight of the mud entering the hole.

c. Other mud properties recorded on the daily drilling log are within the specified ranges required by the mud program.

When the mud in the hole is circulated, the driller's log shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure 517 kPa (75 psi) or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

When there is an indication of swabbing or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

For each casing string, the maximum pressure to be contained under the blowout preventer, before controlling excess pressure by bleeding through the choke, shall be posted near the driller's control console.

An operable vacuum-type gas separator shall be installed in the mud system prior to commencement of drilling operations. The separator shall be maintained for use throughout the drilling and completion of the well.

The mud in the hole shall be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole.

6.2 *Mud Testing and Monitoring Equipment.* Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with procedures outlined in "API Recommended Practice for Standard Procedure for Testing Drilling Fluids," API RP 13B, Seventh Edition, April 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use. The results of the tests shall be recorded and maintained at the drill site.

The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

a. Recording mud pit level indicator to determine mud pit volume gains and losses.

This indicator shall include both a visual and an audio warning device.

b. Mud-volume measuring device for accurately determining mud volumes required to fill the hole on trips.

c. Mud-return indicator to determine that returns essentially equal the pump discharge rate.

d. Gas-detecting equipment to monitor the drilling mud returns, with indicators located in the mud-logging compartment or on the derrick floor. If the indicators are in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the equipment shall be continually manned.

6.3 *Mud Quantities.* The lessee shall include, with his Application for Permit to Drill, a tabulation of well depth versus minimum quantities of mud material, including weighting material, to be maintained at the drill site. The minimum quantities of mud material required shall be based on the following:

a. The volume required to replace the calculated capacity of the downhole and active surface mud system.

b. The quantity of weighting material required to overcome the highest anticipated formation pressure.

When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies.

Daily inventories of mud materials, including weighting material, shall be recorded and maintained at the well site. Drilling operations shall be suspended in the absence of minimum quantities of mud material specified in the table or as modified in the approved plan.

6.4 Safety Precautions in Enclosed Mud-Handling Areas. All enclosed mud-handling areas where dangerous concentrations of combustible gases may accumulate shall be equipped with a ventilation system and with gas monitors. These enclosed areas shall be:

a. Ventilated with high-capacity, mechanical ventilation systems capable of changing the air once every 2 minutes.

b. Maintained at a negative pressure relative to the surrounding areas where discharge to an adjacent enclosed area may be hazardous.

c. Fitted with gas detectors and alarms.

d. Equipped with electrical equipment of the "explosion proof" type. Alternatively, the equipment may be pressurized to prevent the ingress of explosive gases, and where air is used for pressurizing, the air intake shall be located outside of, and as far as practicable from, hazardous areas.

7. Supervision, Surveillance, and Training.

7.1 *Supervision.* A representative of the operator shall provide onsite supervision of drilling operations on a 24-hour basis.

7.2 *Surveillance.* From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with blowout preventers, bridge plugs, or cement plugs.

7.3 *Training.* By December 1, 1979, lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of the USGS Outer Continental Shelf Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, and subsequent revisions thereto.

Any driller, toolpusher, or operator's representative who received training in well-control operations between December 1, 1975, and December 1, 1979, will be credited with having met the training requirements of GSS–OCS–T 1.

After December 1, 1979, in order to maintain qualification, employees must successfully complete a USGS-approved refresher course annually and repeat the basic well-control course every 4 years, as described in the provisions of GSS–OCS–T 1. Credit for these courses shall be obtained from USGS-approved schools. The refresher course shall be completed within 45 days of the student's anniversary date. The anniversary date is established upon the student's successful completion of a basic course in well control.

Records shall be maintained at the drill site for the affected personnel, indicating the specific training and refresher courses successfully completed, the dates of completion, and the names and dates of the courses.

In those Areas which are subject to subfreezing conditions, the lessee shall ensure that personnel responsible for maintenance of the blowout-preventer stack, the associated-control equipment, and the hydraulic-control fluids shall be instructed in the proper procedures to prevent freezing of the hydraulic-control fluids in the control system and the fluids in the choke and kill lines.

8. *Hydrogen Sulfide.* When drilling operations are planned which will penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or in those Areas where the presence of H_2S is unknown, or upon encountering H_2S, the preventive measures and the operating practices set forth in USGS Outer Continental Shelf Standard, "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1 (GSS–OCS–1), Second Edition, June 1979, or subsequent revisions thereto, shall be followed.

9. *Critical Operations and Curtailment Plans.* Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire, explosion, oil spills, and other discharges or emissions. The lessee shall file with the District Supervisor, for approval, a Critical Operations and Curtailment Plan to be followed while conducting drilling operations on each lease. This plan shall include:

a. A list or description of the critical drilling operations that are, or are likely to be, conducted on the lease. This list or description shall specify the operations to be ceased, limited, or not to be commenced under given circumstances or conditions. This list shall include operations such as:

(1) Drilling in close proximity to another well.

(2) Drill-stem testing.

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency, repositioning the vessel on location, and reestablishing entry into the well.

b. A list or description of circumstances or conditions under which such critical operations shall be curtailed. This list or description shall be developed from all the factors and conditions relating to the conduct of operations on the lease, and shall consider but not necessarily be limited to the following:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment and spill-control system response time.

(3) Abnormal or unusual conditions expected to be encountered during drilling operations.

(4) Known or anticipated meterorological or oceanographical conditions.

(5) Availability of personnel and equipment for particular operations to be conducted.

(6) Other factors peculiar to the particular lease under consideration.

c. The name of the person who has overall responsibility, as the person in charge at the site, for safety of drilling operations.

When any circumstance or condition listed or described in the plan occurs or other operational limits are encountered, the lessee shall notify the District Supervisor and shall curtail the critical operations as set forth under 9a.

Deviations from the plan shall require prior approval of the District Supervisor. If emergency action requires deviation from the plan, the District Supervisor shall be notified as soon as possible.

The lessee shall review the plan at least annually. The lessee shall notify the District Supervisor of the results of this review. Any amendments or modifications of the plan are subject to the approval of the District Supervisor.

10. *Field Drilling Rules.* When sufficient geological and engineering information is obtained as a result of drilling operations, the lessee may make an application or the Supervisor may require an application for the establishment of field drilling rules. After field drilling rules have been established by the Supervisor, development wells shall be drilled in accordance with these rules and the requirements of this Order which are not affected by such rules.

11. *Departures.* All departures from the requirements specified in this Order shall be

subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,

Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,

Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey Conservation Division Western Region

ALASKA AREA, ARCTIC

Ocs Order No. 3 Effective

Plugging and Abandonment of Wells

The Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations shall not be commenced prior to obtaining approval from the appropriate District Supervisor. Oral or telegraphic approvals shall be in accordance with 30 CFR 250.13.

1. *Permanent Abandonment.*

1.1 *Isolation of Zones in Open Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (98 feet) below the bottom to 30 meters (98 feet) above the top of any oil, gas, and freshwater zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata or the surface. The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the District Supervisor.

1.2 *Isolation of Open Hole.* Where there is open hole below the casing, a cement plug shall be placed in the deepest casing string in accordance with "a" or "b" below. In the event lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed in accordance with "c" below:

a. A cement plug set by the displacement method so as to extend a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the casing shoe.

b. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the casing shoe, with a cement plug calculated to extend at least 30 meters (98 feet) below the casing shoe and 15 meters (49 feet) above the retainer.

c. A permanent-type bridge plug set within 45 meters (148 feet) above the casing shoe with 15 meters (49 feet) of cement on top of the bridge plug. This bridge plug shall be tested in accordance with subparagraph 1.7 prior to placing subsequent plugs.

1.3 *Plugging or Isolating Perforated Intervals.* A cement plug shall be set by the displacement method opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of setting a cement plug by the dispalcement method, the following two methods are acceptable, provided the perforations are isolated from the hole below:

a. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the top of the perforated interval with a cement plug calculated to extend at least 30 meters (98 feet) below the bottom of the perforated interval and 15 meters (49 feet) above the retainer.

b. A permanent-type bridge plug set within 45 meters (148 feet) above the top of the perforated interval with 15 meters (49 feet) of cement on top of the bridge plug.

1.4 *Plugging of Casing Stubs.* If casing is cut and recovered leaving a stub, one of the following methods shall be used to plug the casing stub.

1.4.1 *Stub Termination Inside Casing String.* A stub terminating inside a casing string shall be plugged by one of the following methods:

a. A cement plug set so as to extend 30 meters (98 feet) above and 30 meters (98 feet) below the stub.

b. A cement retainer set 15 meters (49 feet) above the stub with 45 meters (148 feet) of cement set below and 15 meters (49 feet) above.

c. A permanent bridge plug set 15 meters (49 feet) above the stub and capped with 15 meters (49 feet) of cement.

1.4.2 *Stub Termination Below Casing String.* If the stub is below the next larger string, plugging shall be accomplished in accordance with either subparagraph 1.1 or 1.2.

1.5. *Plugging of Annular Space.* Any annular space communicating with any open hole and extending to the ocean floor shall be plugged with cement.

1.6 *Surface Plug.* A cement plug at least 45 meters (148 feet) in length, with the top of the plug 45 meters (148 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the ocean floor.

1.7 *Testing of Plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

a. By placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer need not be tested.

b. By testing the plug with a minimum pump pressure of 6,900 kPa (1,000 psi) with no more than a 10-percent pressure drop during a 15-minute period.

1.8 *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs. *Fluid left in the hole adjacent to the permafrost zone shall have a freezing point below the temperature of the permafrost zone and shall not have an oil base.*

1.9 *Clearance of Location.* All casing, wellhead, equipment, and piling shall be removed to a depth of at least 5 meters (16 feet) below the ocean floor or at a depth approved by the District Supervisor after a review of data on the ocean-bottom conditions. The operator shall verify that the location has been cleared of all obstructions.

1.10 Cement. The cement used for cement plugs placed across the permafrost zones must be designed to set before freezing and to have a low heat of hydration.

2. *Temporary Abandonment.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for the requirements in subparagraphs 1.6. and 1.9. When a drilling well is temporarily abandoned, a bridge plug or a cement plug shall be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole. When a casing stub extends above the ocean floor, the operator shall comply with the following requirements:

a. A mechanical, retrievable, or permanent bridge plug, or a cement plug at least 30 meters (98 feet) in length shall be set in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

b. The requirements of OCS Order No. 1, paragraph 4, "Identification of Subsea Objects."

3. *Departures.* All departures from the requirements specified in this order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,

Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,

Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division, Western Region

ALASKA AREA, ARCTIC

OCS Order No. 4, Effective

Determination of Well Producibility

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12. An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production of oil and gas in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved in accordance with 30 CFR 250.12.

1. *Application for Determination of Well Producibility.* An application shall be submitted to the District Supervisor for the determination of every new well's capability of producing until a well, drilled on the lease, has been determined to be capable of producing oil or gas in paying quantities. The application shall be submitted within 60 days after the drilling rig has been moved from the well.

2. *Criteria for the Determination of Well Producibility.* The Supervisor shall prescribe which of the following criteria is to be used to determine the capability of a well to produce in paying quantities.

2.1 *Production Tests.* All tests must be witnessed by an authorized respresentative of the U.S. Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided approval is obtained from the District Supervisor prior to the performance of the test. All tests must conform to the following minimum requirements:

a. A production test for oil wells of at least 2 hours' duration following stabilization of flow.

b. A deliverability test for gas wells of at least 2 hours' duration following stabilization of flow or a 4-point back-pressure test.

2.2 *Production Capability Determination.* When the District Supervisor determines that open-hole evaluation data, such as wireline formation tests, drill stem tests, core data, and logs, have been demonstrated as reliable in a geologic area such data may be considered as acceptable evidence that a well is capable of producing in paying quantities.

3. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,

Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,

Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division, Western Region

ALASKA AREA, ARCTIC

OCS Order No. 5, Effective

Production Safety Systems

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and 250.12(a), and in accordance with 30 CFR 250.41(b), 250.42, and 250.46. The lessee shall be responsible for compliance with the requirements of this Order in the installation and operation of the production safety systems on all platforms and structures including those facilities not operated or owned by the lessee. All applications for approval under the provisions of this Order shall be submitted to the District Supervisor.

1. *Technological Improvement.* The lessee is encouraged to continue the development of safety-system technology. As research and product improvement result in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used or required.

2. *Quality Assurance and Performance of Safety and Pollution-Prevention Equipment.* Safety and Pollution-Prevention Equipment (SPPE) shall conform to the following quality assurance standards or subsequent revisions which the Chief, Conservation Division, has approved for use.

a. American National Standards Institute/American Society of Mechanical Engineers Standards "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME SPPE-1-1977, December 1977 (formerly ANSI/ASME-OCS-1-1977).

b. American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME-SPPE-2-1977, December 1977 (formerly ANSI/ASME-OCS-2-1977).

The dates for compliance with these quality assurance standards, the applicable SPPE components, and the applicable SPPE specifications are identified in subparagraph 3.2 and subparagraph 4.2.

3. *Subsurface-Safety Devices.*

3.1 *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-safety device such as a Surface-Controlled Subsurface-Safety Valve (SCSSV), a Subsurface-Controlled Safety Valve (SSCSV), an injection valve, or a tubing plug, unless, after application and justification, the well is determined to be incapable of flowing. The device shall be installed at a depth of 30 meters (98 feet) or more below the ocean floor within 2 days after production is stabilized. *In areas with permafrost, the device shall be installed at a depth of 30 meters (98 feet) or more below the base of the permafrost within 2 days after production is stabilized.*

The well shall be attended at the wellhead while open to a hydrocarbon-bearing zone, unless a subsurface-safety device is installed.

3.1.1 *Subsurface-Safety Valves.* The requirements for subsurface-safety valves vary according to the shut-in tubing pressure of the well. Alternatives to the following requirements may be approved by the Supervisor when greater reliability or safety can be demonstrated.

Wells completed after the effective date of this Order shall be equipped with one of the following:

a. All tubing installations shall be equipped with a surface- or other remotely controlled subsurface-safety device if the shut-in tubing pressure of the well is 27,600 kilopascals (kPa) (4,000 psi) or less.

b. If the shut-in tubing pressure of the well is greater than 27,600 kPa (4,000 psi), the well shall be equipped with a subsurface-controlled subsurface-safety valve. When the shut-in tubing pressure declines below 27,600 kPa (4,000 psi), a surface- or other remotely controlled subsurface-safety valve shall be installed when the tubing is first removed and reinstated.

3.2 *Specification for Subsurface-Safety Valves.* Surface-controlled and subsurface-controlled subsurface-safety valves required by subparagraphs 3.4 and 3.5, which are installed on new installations after July 1, 1979, shall conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Third Edition, November 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use at the time of installation.

3.3 *Design, Installation, and Operation.* After the effective date of this Order, new installations of subsurface-safety valves shall be in accordance with "API Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems," API RP 14B, First Edition, October 1973, or subsequent revisions which the Chief, Conservation Division, has approved for use.

3.4 *Surface-Controlled Subsurface-Safety Valves.* After the effective date of this Order, all tubing installations open to a hydrocarbon-bearing zone shall be equipped with a surface-controlled subsurface-safety valve, except as specified in subparagraphs 3.1, 3.5, and 3.6. The surface controls may be located on the site or at a remote location.

The lessee shall furnish evidence that the surface-controlled subsurface-safety devices and related equipment are capable of normal operation in those Areas which are subject to subfreezing conditions.

3.4.1 *Testing of Surface-Controlled Subsurface-Safety Valves.* Each surface-controlled, or other remotely controlled, subsurface-safety valve installed in a well shall be tested in accordance with Appendix E of API RP 14B, when installed or reinstalled, at least monthly for the first 3 months, and thereafter at intervals not to exceed 6 months. If the device does not operate properly, it shall be promptly removed, repaired, reinstalled, or replaced, and tested to ensure proper operation.

3.5 *Subsurface-Controlled Subsurface-Safety Valves.* Tubing installations in wells completed from single-well and multiwell satellite caissons or jackets and ocean floor completions may be equipped with a subsurface-controlled subsurface-safety valve in lieu of surface- or other remotely controlled subsurface-safety valves.

3.5.1 *Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves.* Each subsurface-controlled subsurface-safety valve installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding:

(1) 6 months for those valves not installed in a landing nipple.

(2) 12 months for those valves installed in a landing nipple.

3.6 *Tubing Plugs in Shut-in Wells.* A tubing plug shall be installed in lieu of, or in addition to, other subsurface-safety devices if a well has been shut in for a period of 6 months. Tubing plugs shall be set at a depth of 30 meters (98 feet) or more below the ocean floor. *In areas containing permafrost, each tubing-plug installation shall be approved by the District Supervisor on a case-by-case basis.* All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed but not placed on production shall be equipped with a subsurface-safety valve or tubing plug within 2 days after completion. A surface-controlled subsurface-safety valve of the pump-through type may be used as a pump-through tubing plug for the purpose of this subparagraph,

provided the surface control has been rendered inoperative. A shut-in well which is equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 400 cc/min or a gas leakage rate in excess of 7d m^3/sec (15 cubic ft/min) is observed, the plug shall be removed, repaired, and reinstalled, or an additional tubing plug may be installed in lieu of removal and repair.

3.7 *Injection Wells.* A surface-controlled subsurface-safety valve or an injection valve capable of preventing backflow shall be installed in all wells placed in injection service after the effective date of this Order.

This requirement is not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually and submit an annual report certifying the no-flow status of the well.

3.8 *Temporary Removal for Routine Operations.* Each wireline or pumpdown-retrievable subsurface-safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Sundry Notice and Report on Wells (Form 9–331), for a period not to exceed 15 days. The well shall be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. The removal of the subsurface-safety device shall be noted in the records as required by subparagraph 3.11g. The well shall be attended at the wellhead until the subsurface-safety device has been reinstalled, unless attendance has been waived by the District Supervisor.

3.9 *Additional Safety Equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface-safety device is installed after the effective date of this Order shall be equipped with a landing nipple, flow couplings to prevent internal abrasion, or other protective equipment, above and below, to provide for the setting of the subsurface-safety valve. The control system for all surface-controlled subsurface-safety valves shall be an integral part of the platform Emergency Shutdown System (ESD) as defined in API RP 14C, Appendix C, Section C1. In addition to the activation of the ESD system by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves shall close in response to shut-in signals from the ESD system or the fire loop, or both.

3.10 *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones in which the subsurface-safety device has been removed, in accordance with the provisions of this Order, shall be identified by a sign on the wellhead stating the subsurface-safety device has been removed. A subsurface-safety device shall be available for each well on the platform. In the event of an emergency such as an impending storm, this device shall be properly installed as soon as possible with due consideration being given to personnel safety.

3.11 *Records.* The lessee shall maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the U.S. Geological Survey (USGS). The records to be maintained shall contain verification of:

a. The design, including make, model, and type. For subsurface-controlled valves, number of the spacers, size of beans, springs, and the pressure settings.

b. The devices having been manufactured in accordance with the quality-assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as reqaired by paragraph 2.

c. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

d. The record of all configuration modifications to the certified design.

e. Installation at the required setting depth and in accordance with the manufacturer's instructions and API RP 14B.

f. The qualifications of the personnel who directed all installations and removals.

g. The results of tests required by this Order, the dates of removals and reinstallations, and the reasons for removals and reinstallations.

h. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

3.12 *Reports.* Well completion reports (Form 9–330) and any subsequent reports of workover (Form 9–331) shall include the type and the depth of the subsurface-safety devices.

4. *Design, Installation, and Operation of Production Safety Systems.* All production facilities, including separators, treaters, compressors, headers, and flowlines, shall be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

The lessee shall furnish evidence that the surface-safety systems and related equipment are capable of normal operation in those Areas which are subject to subfreezing conditions, and that all equipment and operating procedures take into account floating ice, *icing,* and other extreme environmental conditions that may occur in the Area.

4.1 *New Platforms.* New platform production facilities shall be protected with a basic and ancillary surface-safety system designed, analyzed, tested, and maintained in operating condition in accordance with the provisions of "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms," API RP 14C, Second Edition, January 1978, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, or subsequent revisions which the Chief, Conservation Division, has approved for use and the additional requirements of the Order. For this application, the word "should" contained in API RP 14C shall be read "shall," except for those contained in explanatory statements, sections 3.4c and 4.3a(4)(a)–(f). If processing components are to be utilized, other than those for which Safety Analysis Checklists (SAC's) are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system.

4.2 *Specification for Wellhead Surface-Safety Valves.* All wellhead Surface-Safety Valves (SSV's) required by subparagraph 4.1 which are installed on new installations after July 1, 1979, shall conform to "API Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D, Second Edition, November 1977, as amended by Supplement 1, March 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use at the time of installation.

4.3 *Submittal of Safety-System Design and Installation Features.* Prior to installation, the lessee shall submit for approval to the District Supervisor, in duplicate, information relative to design and installation features, as indicated in subparagraphs a through g. This information shall also be maintained at the lessee's onshore field engineering office. All approvals are subject to field verifications. This information shall include:

a. A schematic flow diagram showing size, capacity, and design working pressure of separators, treators, storage tanks, compressors, pipeline pumps, and metering devices.

b. A schematic flow diagram (reference API RP 14C, example: figure E1) and the related Safety Analysis Function Evaluation (SAFE) chart (reference API RP 14C, Subsection 4.3c). These diagrams and charts shall be developed in accordance with the provisions of API RP 14C and the additional requirements of this Order.

c. A schematic piping diagram showing the size and design pressure with reference to welding specification(s) or code(s) used. The maximum-allowable working pressures shall be determined in accordance with "API Recommend Practice for Design and Installation of Offshore Production Platform Piping System," API RP 14E, First Edition, August 1975, and Supplement 2, October 1977, or subsequent revisions which the Chief, Conservation Division, has approved for use. The recommendations contained in API RP 14E are acceptable for the design and installation of the platform piping system.

d. A diagram of the fire-fighting system.

e. Electrical system information including the following:

(1) A plan of each platform deck outlining any nonrestricted area, i.e., areas which are unclassified with respect to electrical equipment installations and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outline shall include the following information:

(a) Any surrounding production or other hydrocarbon source and a description of the deck, overhead, and firewall.

(b) Location of generators, control rooms, panel boards, major cabling or conduit

routes, and identification of the wiring method, including the identification of each wire and cable type that is utilized.

(2) Elementary electrical schematic of any platform safety-shutdown system with a functional legend.

(3) Classification of areas for electrical installations in accordance with the National Electrical Code, 1978 Edition, and with the "API Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Lands and on Marine Fixed and Mobile Platforms," API RP 500B, Second Edition, July 1973, or subsequent revisions which the Chief, Conservation Division, has approved for use.

f. The design and schematics of the installation and maintenance of all fire and gas detection systems shall include the following:

(1) Type, location, and number of detection heads.

(2) Type and kind of alarm, including emergency equipment to be activated.

(3) Method used for detection.

(4) Method and frequency of calibration.

(5) Name of organization to perform system inspection and calibration.

(6) A functional block diagram of the detection system, including the electric power supply.

g. Certification that the design for the mechanical and electrical systems were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the complete installations conform to the approved designs or the lessee shall request approval of the "As-Built" changes.

5. *Additional Safety and Pollution-Control Requirements.* The following requirements modify or are in addition to those contained in API RP 14C.

5.1 *Design, Installation, and Operation.*

5.1.1 *Pressure Vessels.* Pressure vessels shall be designed, fabricated, stamped, and maintained in accordance with specific sections of the ASME Boiler and Pressure Vessel Code as listed below. The pressure vessels shall conform to the July 1, 1977, edition of the Code or subsequent revisions which the Chief, Conservation Division, has approved for use.

a. Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

b. Steam generators shall be equipped with low-water-level controls in accordance with applicable provisions of sections I and IV.

c. The lessee shall determine and record the operating pressure ranges of all pressure-operated vessels in order to establish the pressure-sensor settings. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the vessel. This setting shall also be sufficiently below the relief valve's set pressure to assure that the pressure source is shut in before the relief valve starts relieving. The low-pressure shut-in sensor shall activate no lower than 15 percent or 35 kPa (5 psi), whichever is greater, below the lowest pressure in the operating range.

d. All pressure or fired vessels used in the production of oil or gas, ordered after the effective date of this Order, shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, sections I, IV, and VIII, as appropriate, in effect at the time the vessel is ordered. Uncoded vessels now in use shall have been hydrostatically tested to a pressure 1.5 times their work pressures.

The test date, test pressure, and working pressure shall be marked on the vessel in a prominent place. A record of the test shall be maintained by the lessee in the field area.

5.1.2 *Flowlines.*

a. All flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located downstream of the well choke. All pressure sensors shall be equipped to permit testing with an external pressure source. The lessee shall determine and record the operating pressure ranges in order to establish pressure-sensor settings. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the line; but, in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-list supply pressure to assure actuation of the surface-safety valve. The low-pressure shut-in sensor shall be set no lower than 10 percent or 35 kPa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.

b. If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of, and including, the header inlet valve(s) shall be able to withstand the maximum shut-in pressure of the well, unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Supervisor.

(2) An additional automatic shutdown valve controlled by an independent high-pressure sensor. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid-hydrocarbons which may be relieved to the vessel.

5.1.3 *Pressure Sensors.* Pressure sensors may be of the automatic- or nonautomatic-reset type. When the automatic-reset types are used, a nonautomatic-reset relay shall be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.

5.1.4 *Emergency Shutdown System.* The manually operated ESD valve shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. ESD stations may utilize a loop of breakable synthetic tubing in lieu of a valve. The time for the safety system to effect platform shutdown shall not exceed 45 seconds after the automatic detection of an abnormal condition or the actuation of an ESD station. A schematic of the ESD system shall be posted at a prominent location on the platform. This schematic shall indicate the control functions of all safety devices.

5.1.5 *Engine Exhausts.* Engine exhausts shall be equipped to comply with the insulation and personnel-protection requirements of API RP 14C, Section 4.2c(4). Exhaust piping from internal-combustion engines shall be equipped with spark arrestors.

5.1.6 *Glycol-Dehydration Units.* A pressure relief system or an adequate vent shall be installed on the glycol regenerator, or at a location approved by the District Supervisor, which will prevent overpressurization of all glycol-dehydration units. The set pressure of the pressure-relief system shall be determined by the lessee and approved by the District Supervisor. The discharge of the relief valve must be vented in a nonhazardous manner. The glycol-dehydration unit shall be properly maintained to prevent overpressurization of the unit.

5.1.7 *Gas Compressors.*

a. *New Compressor Installations.* Each compressor installed after the effective date of this Order shall be equipped with the following protective equipment:

(1) A PSH, a PSL, a PSV, and an LSH to protect each interstage scrubber.

(2) An LSL to protect each interstage scrubber, unless the fluid is dumped through a choke restriction to another pressure vessel. An LSL shut-in control(s) installed in interstage scrubber(s) may be designed to actuate the automatic Shutdown Valve(s) (SDV's) installed in the scrubber dump line(s).

(3) A TSH on each compressor cylinder or other components as applicable.

(4) In addition to the provisions of API RP 14C, Subsection A8.3, PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic SDV's located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources.

All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover.

b. *Small Compressor Installations.* Compressor installations of 745 kilowatts (1,000 horsepower) or less are excluded from those requirements of API RP 14C, A8.3d, which provide for installation of a blowdown valve (BDV) on the discharge line.

5.1.8 *Firefighting Systems.* Firefighting systems installed after the effective date of this Order shall conform to Subsection 5.2, "Fire Water Systems," of "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1978, or to subsequent revisions which the Chief, Conservation Division, has approved for use and to the additional requirements of this subparagraph.

A firewater system consisting of rigid pipe with firehose stations shall be installed. A fixed water-spray system shall be installed in the well bays. The system shall be installed to provide needed protection at all times in all areas where production-handling equipment is located.

Acceptable pump drivers include diesel engines, natural gas engines, and electric motors. Fuel or power shall be available for at least 30 minutes of run-time during platform shut-in time. If necessary, an alternate fuel supply shall be installed to provide for this pump-operating time.

A firefighting system using chemicals may be used or may be required in lieu of a water-spray system if the District Supervisor determines that the use of a chemical system provides equivalent fire-protection control. A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the platform or structure.

5.1.9 *Fire and Gas Detection System.*

a. Fire (flame, heat, or smoke) sensors shall be used in all enclosed high-hazard areas. Gas sensors shall be used in all inadequately ventilated, enclosed, high-hazard areas. A high-hazard area is defined as:

(1) Any enclosed area containing a gas source, except a meter house with adequate ventilation.

(2) A compressor building.

(3) Any nonsealed enclosed area within 25 feet of a producing well or service area of a producing well, unless the enclosed area does not contain an ignition source. A diagram of the detection system showing the location of all detection points shall be posted in a prominent place on the platform or structure.

b. All detection systems shall be capable of continuous monitoring. The systems shall be of the manual-reset type.

c. A fuel gas odorant and an automatic gas-detection and alarm system are required in enclosed, continuously manned areas of the facility.

d. The District Supervisor may require a gas detector or alarm in any potentially hazardous area.

e. Fire and gas detection systems shall be of a type as defined in the National Electrical Code, 1978 Edition, or subsequent revisions which the Chief, Conservation Division, has approved for use.

5.1.10 *Electrical Equipment.* The following requirements shall be applicable to all electrical equipment and systems:

a. All engines with ignition systems shall be equipped with a low-tension ignition system of a low-fire-hazard type and shall be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

b. All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

c. At the time of approval, wiring methods shall conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45–1977, or subsequent revisions which the Chief, Conservation Division, has approved for use. Each conductor of a wire, a cable, or a bus bar shall be made of copper on all new installations constructed after the effective date of this Order.

d. An auxiliary power supply shall be installed to provide emergency power, capable of operating all electrical equipment required to maintain safety of operations, in the event a of failure in the primary electrical power supply.

e. The elementary electrical schematic of the platform safety-shutdown system required by subparagraph 4.3e(2) shall be posted in a prominent place on the platform or structure. This schematic shall indicate the control functions of all electrically actuated safety devices.

f. Maintenance of these systems shall be by qualified personnel.

5.1.11 *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. An annual report, by lease, indicating the wells which have erosion-control programs in effect and the results of the programs shall be submitted by the first of December to the appropriate District Supervisor.

5.2 *General Platform Operations.*

a. Safety devices and safety systems on wells which are capable of producing shall not be bypassed or blocked out of service. Safety devices may be bypassed or blocked out of service if they are temporarily out of service due to startup, maintenance, or testing procedures, provided that personnel are monitoring the blocked-out functions. Any device on wells, vessels, or flowlines which is temporarily out of service shall be flagged.

b. When wells are disconnected from producing facilities and blind-flanged or equipped with a tubing plug, compliance is not required with the provisions of API RP 14C of this Order concerning:

(1) Installation of automatic fail-close SSV on wellhead assemblies.

(2) Installation of the PSH and the PSL shut-in sensors downstream of the choke in flowlines from wells.

(3) Installation of flow safety valves (FSV's) in header individual flowlines.

c. All open-ended lines connected to producing facilities shall be plugged or blind-flanged, except those lines designed to be open-ended, such as flare or vent lines.

5.3 *Simultaneous Platform Operations.* Prior to conducting activities simultaneously with production operations which could increase the possibility of occurrence of undesirable events, such as harm to personnel or to the environment or damage to equipment, a "General Plan for Conducting Simultaneous Operations" in a producing field shall be filed for approval with the District Supervisor. This plan shall be modified and updated by supplemental plans when actual simultaneous operations are scheduled. Activities requiring these plans are drilling, completion, workover, wireline, pumpdown, and major construction operations.

The "General Plan for Conducting Simultaneous Operations" shall include:

a. A narrative description of operations.

b. Procedures for the mitigation of potentially undesirable events including:

(1) The guidelines the lessee will follow to assure coordination and control of simultaneous activities.

(2) An indication of the person having overall responsibility at the site for the safety of platform operations.

The "Supplemental Plan for Conducting Simultaneous Operations" shall include:

a. A floor plan of each platform deck indicating critical areas of simultaneous activities.

b. An outline of any additional safety measures that are required for simultaneous operations.

c. Specification of any added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

5.4 *Welding Practices and Procedures.* The following requirements are applicable to any welding practice or procedure performed on:

a. An offshore mobile-drilling unit during the drilling mode.

b. A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity.

c. A platform, structure, artificial island, or other installation during any drilling, completion, workover, or production operation.

d. A platform, structure, artifical island, or other installation which contains a well open to a hydrocarbon-bearing zone.

For the purpose of this Order, the terms "welding" and "burning" are defined to include arc or acetylene cutting and arc or acetylene welding.

Each lessee shall file, for approval by the District Supervisor, a "Welding and Burning Safe Practices and Procedures Plan." The plan shall be filed within 90 days after the effective date of this Order and shall include the qualification standards or requirements for personnel and the methods by which the lessee will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan shall be available in the field area. Any person designated as a welding supervisor shall be thoroughly familiar with this plan.

Prior to welding or burning operations, the lessee shall establish approved safe-welding areas. These areas shall be constructed of noncombustible or fire-resistant materials, be free of combustible or flammable contents, and be suitably segregated from adjacent areas. National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51B, 1971, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guide to designate these areas. A drawing showing the location of these areas shall be posted in a prominent place on the facility. All offshore welding and burning shall be minimized by onshore fabrication when feasible.

All welding equipment shall be inspected prior to beginning any welding or burning.

Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

All welding which cannot be done in the approved safe-welding area shall be performed in compliance with the procedures outlined below:

a. Prior to the commencement of any welding or burning operation on a structure, the lessee's designated person-in-charge at the installation shall personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the lessee-approved qualification standards or requirements for welders. The designated person-in-charge and the welders shall personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the designated person-in-charge shall issue a written authorization for the work.

b. During all welding and burning operations, one or more persons shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual welding or burning operations are in progress. The Fire Watch shall not be a member of the welding crew. If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch shall also maintain a continuous surveillance with a portable gas detector during welding.

c. Prior to any welding or burning operation, the Fire Watch shall have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipment shall be returned to a usable condition.

d. No welding shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered and determined to be safe for welding or burning by the designated person-in-charge.

e. If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded. All other provisions of this section shall also be applicable.

f. If welding or burning operations are conducted on wells or in the well-bay area, all producing wells shall be shut in at the surface-safety valve.

5.5 *Safety Device Testing.* The safety-system devices which are required by this Order shall be tested by the lessee at the interval specified below or more frequently if operating conditions warrant.

Testing shall be in accordance with API RP 14C, appendix D, and the following:

a. All PSV's shall be tested for operation at least annually. These valves shall be either bench-tested or equipped to permit testing with an external pressure source.

b. All Pressure Sensors-High/Low (PSHL) shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

c. All SSV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The SSV's shall be tested for operation in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection L, and tested for leakage in accordance with subsection M. If the valve does not operate properly or any fluid flow is observed in step 3 of the leakage test, the valve shall be repaired or replaced.

d. All flowline FSV's shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection D. If the leakage measured in step 6 exceeds a liquid flow of 400 cc/min or a gas flow of 7 dm^3/sec (15 cubic ft/min), the FSV's shall be repaired or replaced.

e. All LSH and LSL controls shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. These tests shall be conducted by raising and lowering the liquid level across the level-control detector.

f. All automatic inlet SDV's which are actuated by a sensor on a vessel or a compressor shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

g. All SDV's located in liquid-discharge lines and actuated by vessel low-level sensors shall be tested for operation once each calendar month, but at no time shall more than 6 weeks elapse between tests.

h. The TSH shutdown controls installed in all compressors which are protected against abnormal pressures solely by temperature safety devices shall be tested semiannually and repaired or replaced as necessary.

i. All pumps for firefighting water systems shall be inspected and test-operated weekly.

j. All fire (flame, heat, or smoke) and gas detection systems shall be tested for operation and recalibrated semiannually, if necessary.

k. The lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a post-production test and inspection of the integrated system may be conducted.

l. All other safety devices shall be tested annually and repaired or replaced as necessary.

5.6 *Records.* The lessee shall maintain records for a minimum period of 5 years for each surface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the U.S. Geological Survey (USGS). The records shall show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation. The records shall also include all failure and inventory reports required by paragraph 6 of this Order.

5.6.1 *Surface-Safety Valve and Associated Actuator Records.* Records for surface-safety valves and associated actuators which require compliance with paragraph 2 shall contain additional information showing verification of:

a. The devices having been manufactured in accordance with the quality assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

b. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

c. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

5.7 *Safety Device Training.* Prior to the commencement of production, the lessee shall ensure that all personnel engaged in installing, inspecting, testing, and maintaining these safety devices will have been qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T–2, revised October 1975, or subsequent revisions which the Chief, Conservation Division, has approved for use.

Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area.

Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company and if they are directly supervised by a qualified person who is capable of evaluating the impact of the work on the total system.

On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

At the time that the lessee submits the Plan of Development and Production, required by 30 CFR 250.34–2, the lessee shall submit an application for approval to the Chief, Conservation Division, describing the training to be conducted and the methods the lessee will utilize. The application shall include:

a. A designation of the lessee's representative who is responsible for training and coordinating training matters with the USGS.

6. *Failure and Inventory Reporting System (FIRS).* The USGS has established a safety and pollution-prevention device Failure and Inventory Reporting System (FIRS) to enhance the reliability and safety of operations in the OCS. This system applies to offshore structures, including satellites and jackets, which produce or process

hydrocarbons and includes the attendant portions of hydrocarbon pipelines, when physically located on the structure.

When the devices specified herein are used as a part of the production-safety and pollution-prevention system, the lessee shall:

a. Submit an initial inventory and periodic updates in accordance with the procedures described in subparagraph 6.1.3.

b. Report all device failures which occur. The report content and format shall be in accordance with the procedures described in subparagraph 6.1.4.

Inventory and failure data required by this Order shall be submitted to the USGS Conservation Manager in the appropriate regional office.

6.1 *Data and Reporting Requirements.*

6.1.1 *Format.* Inventory and failure data shall be submitted in a format containing the same information that is in the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report Form (Form 9–1995) and as outlined in the respective User's Instruction Booklets. Copies of the forms and booklets may be obtained from the USGS Conservation Manager in the appropriate regional office.

The specific method of submitting the required data may be selected from the following:

a. USGS Forms 9–1994 and 9–1995, using a standard coding convention (e.g., all letters capitalized, Z, I, letter O, number 0).

b. ADP card decks of standard 80-column cards.

c. Magnetic tapes which are 9-track, 800 BPI, unlabeled, blocking cannot exceed 1040 characters, odd parity, single gap (i.e., compatible with IBM equipment EBCDIC).

6.1.2 *Device Coverage.* Inventory and failure reports are to be submitted on the safety- and pollution-prevention devices on offshore structures, including satellites and jackets, which produce or process hydrocarbons, and hydrocarbon pipelines thereon. These reports shall be submitted on the following:

a. Blowdown Valve		(BDV)
b. Burner Flame Detector		(BSL)
c. Check Valve		(FSV)
d. Combustible Gas Detector		(ASH)
e. Emergency Shutdown Valve		(ESD)
f. Level Sensor	High	(LSH)
	Low	(LSL)
	Hi/Lo	(LSHL)
g. Pressure Sensor	High	(PSH)
	Low	(PSL)
	Hi/Lo	(PSHL)
h. Relief Valve		(PSV)
i. Shutdown Valve		(SDV)
j. Surface-Safety Valve		(SSSV)
k. Surface-Safety Valve		(SSV)
l. Temperature Sensor	High	(TSH)
	Low	(TSL)
	Hi/Lo	(TSHL)
m. Valve Actuator on, the shutdown valve, the blowdown valve, the surface-safety valves		(VA)

6.1.3 *Device Inventory Reporting.*

6.1.3.1 *Initial Inventory.*

a. For platforms in existence at the time this Order becomes effective, a complete inventory of the safety and pollution-prevention devices shall be submitted no later than 6 months after the effective date of this Order.

b. For platforms completed after this Order becomes effective, a complete inventory of the safety and pollution-prevention devices shall be submitted no later than 1 month after the initial platform production date.

6.1.3.2 *Inventory Updates.* An updating of or addition/deletion to the latest inventory shall be submitted on a monthly basis so as to maintain a current and accurate data base. The inventory will be updated by using the contents of the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995).

Inventory updating due to the addition, deletion, or changeout of a device is accomplished by the lessee's reporting of all the data required on the Safety Device Inventory Report (9–1994).

Whenever a device fails and is either replaced with a new device or "fixed" and put back into service, the inventory shall be updated to reflect this change. Inventory updating, due to the failure of a device, will be performed by the USGS, using the contents of the Safety Device Failure Report (Form 9–1995). Inventory updating information shall be received no later than 30 days following the month in which the device change was made.

6.1.3.3 *Inventory-Reporting Methods.* Inventory data shall be reported either on the Safety Device Inventory Reporting forms (Form 9–1994), punched cards, or magnetic tapes.

The reports shall contain all of the required information in the standard format as described in subparagraph 6.1.1.

6.1.3.4 *Inventory Verification.* The device inventory shall be verified by the lessee to ensure that the inventory data base is maintained on a current basis and that changes are being incorporated as they occur. The verification shall be accomplished no more frequently than once each 6-month period. When verification is required, the USGS will provide the lessee with a copy of the information on record, in the lessee's selected reporting format. The lessee shall review the information and either submit a letter stating that the information is correct, or make the appropriate corrections to the information provided by the USGS. The letter or appropriate corrections shall be received no later than 30 days following the month in which the inventory information which is to be verified was forwarded to the lessee.

6.1.3.5 *Inventory-Reporting Deviation.* A lessee may submit an inventory, update, or verification report differing from that described in subparagraph 6.1.3 when authorized by the USGS.

6.1.4 *Device Failure Reporting.*

6.1.4.1 *Failure-Data Submittal.* Device failure data shall be recorded as soon as possible after detecting the failure as defined in subparagraph 6.1.4.3. This data shall be received no later than 30 days following the month in which the failure was detected. This data must contain all of the required information and be submitted in the standard format either on Safety Device Failure Report forms (Form 9–1995), punched cards, or magnetic tape, as previously described in subparagraph 6.1.1. Information on the failed device must match that previously submitted in inventory reporting. A formal failure analysis is not required by this Order, but each failed device shall undergo sufficient test/disassembly to establish the basic cause(s) of the failure.

6.1.4.2 *Failure-Data Verification.* After receipt of the complete failure data from the lessees, a printout shall be made of all failures by manufacturer, model, and reported cause. Each manufacturer listed shall be furnished a copy of the printout containing the reported failures of his devices only. If he disagrees with the reported failure causes, he is invited to investigate the questioned causes in coordination with the reporting lessee and provide a coordinated reply within 30 days after receipt of the printout. If no reply is received within that time period, the originally reported causes shall be considered to be correct, and the data shall be evaluated accordingly.

6.1.4.3. *Failure Definition.* The safety and pollution-prevention device Failure and Inventory Reporting System does not differentiate between a malfunction and a failure. For the purpose of this program, a failure is defined as the inability of a device to perform its designed function within specified limits. A device is considered to have failed if it does not operate (perform its function) as required within the specified tests' tolerances.

A failure report is not required for:

a. Adjustments made within specified tolerances.

b. Adjustments required due to changes in operating conditions.

7. *Crane Operations.* Cranes shall be operated and maintained to ensure the safety of facility operations in accordance with the provisions of "API Recommended Practice for Operation and Maintenance of Offshore Cranes," API RP 2D, October 1972, or subsequent revisions which the Chief, Conservation Division, has approved for use. Records of inspection, testing, maintenance, and crane operators qualified in accordance with the provisions of API RP 2D shall be kept in the field area for a period of 2 years.

"API Specification for Offshore Cranes," API Specification 2C, February 1972, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guideline for the selection of cranes.

8. *Employee Orientation and Motivation Programs for Personnel Working Offshore.* The lessee shall make a planned, continuing effort to eliminate accidents due to human error. This effort shall include the training of personnel in their functions. A program to achieve safe and pollution-free operations shall be established. This program shall include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T–1, January 1974, or subsequent revisions which the Chief, Conservation Division, has approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations,"API Bulletin T–5, September 1974, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guide in developing employee safety and pollution-prevention motivation programs.

9. *Requirements for Drilling Rigs.*

9.1 *Fixed Structures.* The following requirements contained in this Order are applicable to drilling rigs on fixed structures:

a. Subparagraph 5.1.10, "Electrical Equipment."

b. Subparagraph 5.4, "Welding Practices and Procedures."

c. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

9.2 *Mobile Drilling Units.* The following requirements contained in this Order are applicable to drilling rigs on mobile drilling units:

a. Subparagraph 5.4, "Welding Practices and Procedures."

b. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

10. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,
Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,
Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division, Western Region

ALASKA AREA, ARCTIC

OCS Order No. 7, Effective

Pollution Prevention and Control

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. The lessee shall comply with the following requirements.

1. *Pollution Prevention.* During the exploration, development, production, and transportation of oil and gas, the lessee shall prevent pollution of the ocean. Furthermore, by the disposal of waste materials into the ocean, the lessee shall not create conditions which will adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

1.1 *Liquid Disposal.*

1.1.1 *Drilling-Mud Components.* The lessee shall submit, as a part of the Application for Permit to Drill (Form 9–331 C), a detailed list of drilling-mud components including the common chemical or chemical trade name of each component, a list of the drilling-mud additives anticipated for use in meeting special drilling requirements, and the proposed method of drilling-mud disposal. The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of drilling-mud disposal into the ocean shall be obtained from the District Supervisor; each request will be decided on a case-by-case basis.

1.1.2 *Hydrocarbon-Handling Equipment.* All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of the ocean shall be undertaken immediately.

1.1.3 *Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units.*

a. *Fixed Platforms, Structures, and Artificial Islands.* Curbs, gutters, and drains shall be installed in all deck areas to collect all contaminants in a closed sump. When open decks are used, drip pans or the equivalent shall be placed under equipment and piped to a closed sump. Closed sumps shall automatically maintain fluid at a level sufficient to prevent the discharge of oil into the ocean. Contaminants that are removed from sumps shall be disposed of in a manner which will not create pollution.

All walking and working surfaces shall be equipped with proper drainage to provide safety for personnel and to prevent pollution.

On artificial islands, all vessels containing hydrocarbons shall be placed inside an impervious berm. The volume enclosed by the berm must be in excess of the volume of the vessels containing hydrocarbons. In addition, the rig mat must be made impervious, and all drainage ditches must be directed away from the drilling rig to an impervious sump.

b. *Mobile Drilling Units.* Curbs, gutters, and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3a.

Curbs, gutters, and drains which collect contaminants not associated with the drilling operations are subject to regulation by the U.S. Coast Guard.

1.1.4 *Dischargers from Fixed Platforms or Structures and Mobile Drilling Units.* Discharges from fixed platforms or structures and mobile drilling units, including sanitary waste, produced water, drilling mud, and deck drainage, are subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended.

1.2 *Solid Material Disposal.*

1.2.1 *Well Solids.* The disposal of drill cuttings, sand, and other well solids containing oil is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

1.2.1 *Containers.* Containers and other similar solid-waste materials shall not be disposed of into the ocean.

1.2.3 *Equipment.* Disposal of equipment into the ocean is prohibited except under emergency conditions. The location and description of any equipment disposed of into the ocean shall be reported to the District Supervisor and to the U.S. Coast Guard in accordance with paragraph 4 of OCS Order No. 1.

2. *Personnel, Inspections, and Reports.*

2.1 *Personnel.* The lessee's personnel shall be instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Contractor personnel providing services offshore shall be informed in writing, prior to executing contracts, of the lessee's obligations to prevent pollution and of the provisions of this Order.

2.2 *Pollution Inspections.*

2.2.1 *Manned Facilities.* Manned drilling and production facilities shall be inspected daily to determine if pollution is occurring. Maintenance or repairs which are necessary to prevent pollution of the ocean waters shall be undertaken and performed immediately.

2.2.2 *Unattended Facilities.* Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected daily or at intervals prescribed by the District Supervisor to determine if pollution is occurring. Necessary maintanance or repairs shall be made immediately.

2.3 *Pollution Reports.* All spills of oil and liquid pollutants shall be reported orally to the District Supervisor and shall be confirmed in writing. All reports shall include the cause, location, volume of spill, and action taken. Reports of spills of more than 5.0 cubic meters (31.5 barrels) shall include information on the sea state, meteorological conditions, size, and appearance of slick. All spills of oil and liquid pollutants shall also be reported in accordance with the procedure contained in 33 CFR 153.203.

2.3.1 *Spills.* Spills shall be reported orally within the following time limits:

a. Within 12 hours, if spills are 1.0 cubic meters (6.3 barrels) or less.

b. Without delay, if spills are more than 1.0 cubic meters (6.3 barrels).

2.3.2 *Observed Malfunctions.* Lessees shall notify each other of observed pollution resulting from another's operation.

3. *Pollution-Control Equipment and Materials and Oil Spill Contingency Plans.* The lessee shall submit a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an oil spill which might occur during exploration or development activities. The following subparagraphs describe the minimum requirements for pollution-control equipment and procedures.

3.1 *Equipment and Materials.* Pollution-control equipment and materials shall be maintained by, or shall be available to, each lessee at an offshore location or at a location approved by the Supervisor. The equipment shall include containment booms, skimming apparatus, cleanup materials, and chemical agents which shall be available prior to the commencement of operations. The equipment and materials shall be inspected monthly and maintained in a state of readiness for use. The results of the inspections shall be recorded and maintained at the site.

3.2 *Oil Spill Contingency Plans.* The lessee shall submit an Oil Spill Contingency Plan for approval by the Supervisor, prior to the approval of an Exploration Plan or a Development and Production Plan. Oil Spill Contingency Plans shall be reviewed annually. All modifications of the Oil Spill Contingency Plan and the results from the review of the plan shall be submitted to the

Supervisor for approval. The Oil Spill Contingency Plan shall contain the following:

a. Provisions to assure that full resource capability is known and can be committed during an oil spill, including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

b. Provisions for varying degrees of response effort depending on the severity of the oil spill.

c. Provisions of identifying and protecting areas of special biological sensitivity.

d. Establishment of procedures for the purpose of early detection and timely notification of an oil spill including a current list of names, telephone numbers, and addresses of the responsible person and alternates on call to receive notification of an oil spill; and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

e. Provisions for well-defined and specific actions to be taken after discovery and notification of an oil spill, including:

(1) Specification of an oil-spill-response operating team consisting of trained, prepared, and available operating personnel.

(2) Predesignation of an oil-spill-response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations.

(3) A preplanned location for an oil-spill-response operations center and a reliable communication system for directing the coordinated overall response operations.

(4) Provisions for disposal of recovered spill materials.

4. *Drills and Training.*

4.1 *Drills.* Drills for familiarization with pollution-control equipment and operational procedures shall be held by the lessee. The personnel identified as the oil-spill-response operating team in the Contingency Plan shall participate in these drills. The drills shall be realistic and shall include deployment of equipment. A time schedule with a list of equipment to be deployed shall be submitted to the Supervisor for approval. The drill schedule shall provide sufficient advance notice to allow U.S. Geological Survey (USGS) personnel to witness any of the drills. Drills shall be recorded, and the records shall be made available to USGS personnel. Where drill performance and results are deemed inadequate, the Supervisor may require an increase in the frequency or a change in the location of the drills until satisfactory results are achieved.

4.2 *Training.* The lessee shall ensure that training classes for familiarization with pollution-control equipment and operational procedures are provided of the oil-spill-response operating team. The supervisory personnel responsible for directing the oil-spill-response operations shall receive oil-spill-response instruction *suitable for all seasons.* The lessee shall retain course-completion certificates or attendance records issued by the organization where the instruction is provided. These records shall be available to any authorized representative of the USGS, upon request.

5. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the lessee's Oil Spill Contingency Plan shall be subject to modification when directed by the Supervisor. The primary jurisdiction to require corrective action to abate the source of pollution shall remain with the Supervisor, pursuant to the provisions of this Order and the Memorandum of Understanding (MOU) between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey) dated August 18, 1971. The use of chemical agents or other additives shall be permitted only after approval by the Supervisor in accordance with Annex X, National Oil and Hazardous Substances Pollution Contingency Plan and in accordance with the previously mentioned MOU.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,
Oil and Gas Supervisor, Arctic Area.

Approval:
Don E. Kash,
Chief, Conservation Division.

DEPARTMENT OF THE INTERIOR

Geological Survey, Conservation Division, Western Region

ALASKA AREA, ARCTIC

OCS Order No. 12, Effective

Public Inspection of Records

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.97, 252.6, and 43 CFR Part 2. Requests for information made under the Freedom of Information Act, 5 U.S.C. § 552, will be governed by the provisions of 43 CFR Part 2 (40 FR 7304, February 19, 1975).

1. *Filing of Reports.* All reports on Forms 9–152, 9–330, 9–331, 9–331 C, 9–1869, 9–1870 and the forms used to report the results of multipoint back-pressure tests shall be filed by the lessee in accordance with the following:

a. All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. This copy of the form shall be made available for public inspection.

b. All items on the form not marked "Public Information" shall be completed in full, and such forms and all attachments thereto shall not be available for pu' lic inspection.

c. The copy marked "Public Information" shall be completed in full except that the items described in subparagraphs 2.1 through 2.4 below and the attachments relating to such items may be excluded.

2. *Availability of Records.* It has been determined that certain records pertaining to leases and wells in the OCS and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office.

2.1 *Form 9–152—Monthly Report of Operations.* All information contained on this form shall be available except the information required in the "Remarks" column.

2.2 *Form 9–330—Well-Completion or Recompletion Report and Log.*

2.2.1 *Prior to Commencement.* Prior to commencement of production, all information contained on this form shall be available except:

a. Item 1a, Type of Well.

b. Item 4, Location of Well, at top production interval and at total depth.

c. Item 22, If Multiple Completion, how many.

d. Item 24, Producing Interval.

e. Item 26, Type Electric and Other Logs Run.

f. Item 28, Casing Record.

g. Item 29, Liner Record.

h. Item 30, Tubing Record.

i. Item 31, Perforation Record.

j. Item 32, Acid, Shot, Fracture, Cement Squeeze, Etc.

k. Item 33, Production.

l. Item 37, Summary of Porous Zones.

m. Item 38, Geologic Markers.

2.2.2 *After Commencement of Production.* After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

2.2.3 *5 Years' Elapsed Time.* If production has not commenced after an elapsed time of 5 years from the date of filing Form 9–330 as required in 30 CFR 250.36(b), excluding the total time that operations and production are suspended by direction of the Secretary of the Interior or his duly authorized representative, and further excluding the total time that operations and production are stopped or prohibited by Court order, all information contained on this form shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive of exceptions noted above, the lessee shall file a Form 9–330 containing all information requested on the form except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9–330.

2.3 *Form 9–331–Sunday Notices and Reports on Wells.*

2.3.1 "Request for Approval to." When used as a "Request for Approval to:" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, at top production interval and at total depth, and Item 17, Describe Proposed or Completed Operations.

2.3.2 *"Subsequent Report of."* When used as a "Subsequent Report of:" operations, and after commencement of production, all information contained in this form shall be available, except information contained in Item 17 pertaining to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

2.4 *Form 9–331 C—Application for Permit to Drill, Deepen, or Plug Back.* All information contained on this form and the

location plat attached thereto shall be available except Item 4, Location of Well at Proposed Production Zone, and Item 23, Proposed Casing and Cementing Program.

2.5 *Form 9–1869—Quarterly Oil-Well-Test Report.* All information contained on this form shall be available.

2.6 *Form 9–1870—Semi-Annual Gas-Well-Test Report.* All information contained on this form shall be available.

2.7 *Multi-point Back-Pressure-Test Report.* All information contained in this report shall be available.

2.8 *Sales of Lease Production.* Information contained on the monthly U.S. Geological Survey computer printout showing sales volumes, value, and royalty on production of oil, condensate, gas, and liquid products by lease shall be made available.

2.9 *Availability of Inspection Records.* All accident-investigation reports, pollution-incident reports, facilities-inspection data, and records of enforcement actions are also available for public inspection.

2.10 *Availability of Data and Information Submitted by Lessees.* It has been determined that much information submitted by lessees, as a result of OCS Orders and OCS Notices to Lessees and Operators, is nonproprietary in nature or that release of such information is necessary for the proper development of the lease. This information will be made available for public inspection, except for those portions which the lessee shall designate, with the Supervisor's approval, as trade secrets and commercial or financial information which is privileged or confidential. The available information will include:

a. Notices of support activity.

b. Oceanographic and meteorological data collected from drilling units and production facilities during the period of operations.

c. Results of site surveys required prior to drilling or placement of platforms or structures, such as shallow geologic hazards surveys, archeological/cultural resource surveys, or other surveys related to the placement of platforms or structures.

d. Drawings, maximum environmental design criteria, and rated capability data of mobile drilling units and structures.

e. Oil Spill Contingency Plans.

f. Critical Operations and Curtailment Plans.

g. Other data required under 30 CFR 250.34.

2.11 *Expired Leases.* All information is available upon the expiration of a lease.

3. *Information Exempt from Public Inspection.* The information in subparagraphs 2.1 through 2.4 which has been restricted from public inspection is classified as geological and geophysical data. The release of this data is subject to the following restrictions.

3.1 *Leases Issued Prior to June 11, 1976.* For leases issued prior to June 11, 1976, the classified data is exempt from disclosure under exemption No. (9) of the Freedom of Information Act (5 U.S.C. 552(b)(9) and 43 CFR 2.13 subsection (c), *"Statutory Exemptions,"* (9)).

3.2 *Leases Issued After June 11, 1976.* For leases issued after June 11, 1976, the classified data is available in accordance with 30 CFR 250.97, *Public Inspection of Records,* as follows:

a. *Geophysical Data.* Geophysical data shall not be available for public inspection, except as provided in 2.10c, without consent of the lessee as long as the lease remains in effect or for a period of 10 years after the date of submission, whichever is less, unless the Supervisor, with the approval of the Director, determines that earlier release of this information is necessary for proper development of the field or area.

b. *Geological Data.* Geological data shall not be made available for public inspection without the consent of the lessee as long as the lease remains in effect or for a period of 2 years after the date of submission, whichever is less, unless the Supervisor, with the approval of the Director, determines that earlier release of such information is necessary for the proper development of the field or area. In accordance with 30 CFR 250.38, *Well Records,* data and well records shall be transmitted to the Supervisor upon request or, if not requested, within 30 days following completion of suspension of any well.

For the purpose of orderly release of data, in all cases the date of submission will be considered to be 30 days following such completion or suspension.

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Rodney A. Smith,

Oil and Gas Supervisor, Arctic Area.

Approved:

Don E. Kash,

Chief, Conservation Division.

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